SUBCHAPTER B : COMBUSTION AT EXISTING MAJOR SOURCES

UTILITY ELECTRIC GENERATION

§117.101. Applicability.

(a) The provisions of this undesignated head (relating to Utility Electric Generation) shall apply to utility boilers, steam generators, auxiliary steam boilers, and gas turbines used in an electric power generating system owned or operated by a municipality or a Public Utility Commission of Texas regulated utility located within the Houston/Galveston and Beaumont/ Port Arthur ozone nonattainment areas.

(b) The provisions of this undesignated head are applicable for the life of each affected unit within an electric power generating system or until this undesignated head or sections of this title which are applicable to an affected unit are rescinded.

Adopted 05/11/93 Effective 06/09/93

§117.103. Exemptions.

(a) The provisions of §117.105 of this title (relating to Emission Specifications) or §117.107 of this title (relating to Alternative System-Wide Emission Specifications) shall not apply during periods of major upset or maintenance under the requirements of §101.6 of this title (relating to Notification Requirements for Major Upset), §101.7 of this title (relating to Notification Requirements for Maintenance), and §101.11 of this title (relating to Exemptions from Rules and Regulations).

(b) Units exempted from the provisions of this undesignated head (relating to Utility Electric Generation), except for §117.109(b)(1) of this title (relating to Initial Control Plan Procedures) and §117.113(h) of this title (relating to Continuous Demonstration of Compliance), include the following:

(1) any new units placed into service after November 15, 1992;

(2) any utility boiler, steam generator, or auxiliary steam boiler with an annual heat input less than or equal to $2.2(10^{11})$ Btu per year; or

(3) stationary gas turbines and engines, which are:

(A) used solely to power other engines or gas turbines during start-ups; or

(B) demonstrated to operate less than 850 hours per year, based on a rolling 12-month average.

(c) The fuel oil firing emission limitation of §117.105(c) or §117.107(b) of this title shall not apply during an emergency operating condition declared by the Electric Reliability Council of Texas or the Southwest Power Pool, or any other emergency operating condition which necessitates oil firing. All findings that emergency operating conditions exist are subject to the approval of the Executive Director. The owner or operator of an affected unit shall give the Executive Director and any local air pollution control agency having jurisdiction verbal notification as soon as possible but no later than 48 hours after declaration of the emergency. Verbal notification shall identify the anticipated date and time oil firing will begin, duration of the emergency period, affected oil-fired equipment, and quantity of oil to be fired in each unit, and shall be followed by written notification containing this information no later than five days after declaration of the emergency. The owner or operator of an affected unit shall give the Executive Director and any local air pollution control agency having jurisdiction final written notification as soon as possible but no later than two weeks after the termination of emergency fuel oil firing. Final written notification shall identify the actual dates and times that oil firing began and ended, duration of the emergency period, affected oil-fired equipment, and quantity of oil fired in each unit.

Adopted 05/25/94 Effective 06/23/94

§117.105. Emission Specifications.

(a) No person shall allow the discharge into the atmosphere from any utility boiler, steam generator, or auxiliary steam boiler, emissions of nitrogen oxides (NO_x) in excess of 0.26 pound per million (MM) Btu heat input on a rolling 24-hour average and 0.20 pound per MMBtu heat input on a 30-day rolling average while firing natural gas or a combination of natural gas and waste oil.

(b) No person shall allow the discharge into the atmosphere from any utility boiler or steam generator, NO_x emissions in excess of 0.38 pound per MMBtu heat input for tangentially-fired units on a rolling 24-hour averaging period or 0.43 pound per MMBtu heat input for wall-fired units on a rolling 24-hour averaging period while firing coal.

(c) No person shall allow the discharge into the atmosphere from any utility boiler, steam generator, or auxiliary steam boiler, NO_x emissions in excess of 0.30 pound per MMBtu heat input on a rolling 24-hour averaging period while firing fuel oil only.

(d) No person shall allow the discharge into the atmosphere from any utility boiler, steam generator, or auxiliary steam boiler, NO_x emissions in excess of the heat input weighted average of the applicable emission limits specified in subsections (a)-(c) of this section on a rolling 24-hour averaging period while firing a mixture of natural gas and fuel oil, as follows:
Emission Limit = [a(0.26) + b(0.30)]/(a + b)

Where:

a = the percentage of total heat input from natural gas.
b = the percentage of total heat input from fuel oil.

(e) Each auxiliary steam boiler which is an affected facility as defined by New Source Performance

Standards (NSPS) 40 Code of Federal Regulations (CFR), Part 60, Subparts D, Db, or Dc shall be limited to the applicable NSPS NO_x emission limit, unless the boiler is also subject to a more stringent permit emission limit, in which case the more stringent emission limit applies. Each auxiliary boiler subject to an emission specification under this subsection is not subject to the emission specifications of subsection (a) or (c) of this section.

(f) No person shall allow the discharge into the atmosphere from any stationary gas turbine with a megawatt (MW) rating greater than or equal to 30 MW and an annual electric output in MW-hours (MW-hr) of greater than or equal to the product of 2,500 hours and the MW rating of the unit, NO_x emissions in excess of a block one-hour average of 42 parts per million by volume (ppmv) at 15% oxygen (O_2), dry basis, while firing natural gas.

(g) No person shall allow the discharge into the atmosphere from any stationary gas turbine with a MW rating greater than or equal to 30 MW and an annual electric output in MW-hr of greater than or equal to the product of 2,500 hours and the MW rating of the unit, NO_x emissions in excess of a block one-hour average of 65 ppmv at 15% O_2, dry basis, while firing fuel oil.

(h) No person shall allow the discharge into the atmosphere from any stationary gas turbine used for peaking service with an annual electric output in MW-hr of less than the product of 2,500 hours and the MW rating of the unit, NO_x emissions in excess of a block one-hour average of 0.20 pound per MMBtu heat input while firing natural gas.

(i) No person shall allow the discharge into the atmosphere from any stationary gas turbine used for peaking service with an annual electric output in MW-hr of less than the product of 2,500 hours and the MW rating of the unit, NO_x emissions in excess of a block one-hour average of 0.30 pound per MMBtu heat input while firing fuel oil.

(j) No person shall allow the discharge into the atmosphere from any utility boiler, steam generator, or auxiliary steam boiler subject to this undesignated head (relating to Utility Electric Generation), carbon monoxide (CO) emissions in excess of 400 ppmv based on a rolling 24-hour averaging period.

(k) No person shall allow the discharge into the atmosphere from any stationary gas turbine with a MW rating greater than or equal to 10 MW, CO emissions in excess of a block one-hour average of 132 ppmv at 15% O_2, dry basis.

(l) No person shall allow the discharge into the atmosphere from any unit subject to this undesignated head, ammonia emissions in excess of 20 ppmv based on a block one-hour averaging period.

(m) The NO_x emission limits specified in subsections (a)-(i) of this section shall apply at all times, except as specified in §117.103 of this title (relating to Exemptions) and §117.107 of this title (relating to Alternative System-Wide Emission Specifications). The emission limits specified in subsections (j), (k), and (l) of this section shall apply at all times, except as specified in §117.103 of this title.

(n) For purposes of this subchapter, the following shall apply:

(1) The lower of any permit NO_x emission limit in effect on June 9, 1993 under a permit issued pursuant to Chapter 116 of this title (relating to Control of Air Pollution by Permits for New Construction or Modification) and the NO_x emission limits of subsections (a)-(i) of this section shall apply, except that gas-fired boilers operating under a permit issued after March 3, 1982, with an emission limit of 0.12 pound NO_x per MMBtu heat input, shall be limited to that rate for the purposes of this subchapter.

(2) For any unit placed into service after June 9, 1993 and prior to May 31, 1995 or the final compliance date as approved under the provisions of §117.540 of this title (relating to Phased Reasonably Available Control Technology (RACT)), as functionally identical replacement for an existing unit or group of units subject to the provisions of this chapter and limited to the cumulative maximum rated capacity of the units replaced, the higher of any permit NO_x emission limit under a permit issued after June 9, 1993 pursuant to Chapter 116 of this title and the emission limits of subsections (a)-(i) of this section shall apply. Any emission credits resulting from the operation of such replacement units shall be limited to the cumulative maximum rated capacity of the units replaced. The inclusion of such new units is an optional method for complying with the emission limitations of §117.107 of this title. Compliance with this paragraph does not eliminate the requirement for new units to comply with Chapter 116 of this title.

Adopted 05/25/94 Effective 06/23/94

§117.107. Alternative System-Wide Emission Specifications.

(a) An owner or operator of any gaseous- or coal-fired utility boiler or stationary gas turbine may achieve compliance with the nitrogen oxides (NO_x) emission limits of §117.105 of this title (relating to Emission Specifications) by achieving compliance with a system-wide emission limitation, except as provided for in subsection (d) of this section. Any owner or operator who elects to comply with system-wide emission limits shall reduce emissions of NO_x from affected units so that, if all such units were operated at their maximum rated capacity, the system-wide emission rate from all units in the system would not exceed the system-wide emission limit as defined in §117.10 of this title (relating to Definitions), and shall establish enforceable emission limits for each affected unit in the system. A pound per million (MM) Btu emission limit based on a rolling 24-hour averaging period and a pound per MMBtu emission limit based on a rolling 30-day averaging period shall apply to each gas-fired unit in the system. A pound per MMBtu emission limit based on a rolling 24-hour averaging period shall apply to each coal-fired unit in the system. For stationary gas turbines, the emission limits shall be assigned in the units given by the appropriate emission limitation of §117.105 of this title.

(b) An owner or operator of any fuel oil-fired utility boiler may achieve compliance with the NO_x emission limits of §117.105 of this title by achieving compliance with a system-wide emission limitation. Any owner or operator who elects to comply with system-wide emission limits for oil firing shall reduce emissions of NO_x from affected units so that, if all such units were operated at their average activity level for fuel oil firing as defined in §117.10 of this title, the system-wide emission rate from all oil-fired units in the system would not exceed the system-wide emission limit as defined in §117.10 of this title, and shall establish enforceable emission limits for oil firing for each affected unit in the system. A pound per MMBtu emission limit based on a rolling 24-hour averaging period shall apply to each oil-fired unit in the system. The emission limit assigned to each oil-fired unit in the system shall not exceed 0.5 pound NO_x per MMBtu based on a rolling 24-hour average.

(c) An owner or operator of any gaseous and liquid fuel-fired utility boiler, steam generator, or gas turbine shall calculate the gaseous and liquid fuel-fired system-wide emission limits of subsections (a) and (b) of this section separately. The owner or operator shall also:

(1) comply with the assigned maximum allowable emission rate while firing natural gas only;

(2) comply with the assigned maximum allowable emission rates for liquid fuel while firing liquid fuel only; and

(3) comply with a limit calculated as the actual heat input weighted sum of the assigned gas-firing allowable emission limit and the assigned liquid-firing allowable emission limit while operating on liquid and gaseous fuel concurrently.

(d) Peaking gas turbines subject to the emission limits of §117.105(h) or (i) of this title and auxiliary steam boilers subject to the emission limits of §117.105(a), (c), (d), or (e) of this title shall comply with those individual emission specifications under this section and shall not be included in the system-wide emission specification. Coal-fired utility boilers or steam generators shall be treated as a separate system, and system averaging for coal-fired utility boilers or steam generators shall be limited to those units under this section.

(e) Solely for purposes of calculating the system-wide emission limit, the allowable mass emission rate for each affected unit shall be calculated from the emission specifications of §117.105 of this title, as follows.

(1) The NO_x emissions rate (in pounds per hour) for each affected utility boiler, steam generator, or auxiliary steam boiler is the product of its average activity level for fuel oil firing or maximum rated capacity for gas firing and its NO_x emission specification of §117.105 of this title.

(2) The NO_x emissions rate (in pounds per hour) for each affected stationary gas turbine is the product of the in-stack NO_x, the turbine manufacturer's rated exhaust flow rate (expressed in pounds per hour at megawatt (MW) rating and International Standards Organization (ISO) flow conditions), and $(46/28)(10^{-6})$;

Where:

In-stack NO_x	=	NO_x (allowable) x $(1 - \%H_2O/100)$ x $[20.9 - \%O_2/(1 - \%H_2O/100)]/5.9$
NO_x (allowable)	=	the applicable NO_x emission specification of §117.105(f) or (g) of this title (expressed in parts per million by volume NO_x at 15% oxygen (O_2) dry basis)
$\%H_2O$	=	the volume percent water in the stack gases, as calculated from the manufacturer's data, or other data as approved by the Executive

Director, at MW rating and ISO flow conditions

$\%O_2$ = the volume percent O_2 in the stack gases on a wet basis, as calculated from the manufacturer's data, or other data as approved by the Executive Director, at the MW rating and ISO flow conditions.

Adopted 05/25/94 Effective 06/23/94

§117.109. Initial Control Plan Procedures.

(a) The owner or operator of any major source of nitrogen oxides (NO_x) shall submit, for the approval of the Executive Director, an initial control plan for installation of NO_x emissions control equipment and demonstration of anticipated compliance with other applicable requirements of this subchapter. The Executive Director shall approve the plan if it contains all the information specified in this section. Revisions to the initial control plan shall be submitted with the final control plan.

(b) The initial control plan shall be submitted in accordance with the schedule specified in §117.510(1) of this title (relating to Compliance Schedule For Utility Electric Generation) and shall contain the following:

(1) a list of all combustion units at the source with a maximum rated capacity greater than 5.0 million Btu per hour; all stationary, reciprocating internal combustion which are located in the Houston/Galveston ozone nonattainment area and rated 150 horsepower (hp) or greater, or located in the Beaumont/Port Arthur ozone nonattainment area and rated 300 hp or greater; all stationary gas turbines with a megawatt (MW) rating of greater than or equal to 1.0 MW; to include the maximum rated capacity, anticipated annual heat input capacity factor, the facility identification numbers and emission point numbers as submitted to the Emissions Inventory Section of the Texas Natural Resource Conservation Commission (TNRCC), and the emission point numbers as listed on the Maximum Allowable Emissions Rate Table of any applicable TNRCC permit for each unit;

(2) identification of all units subject to the emission specifications of §117.105 or §117.107 of this title (relating to Emission Specifications and Alternative System-Wide Emission Specifications);

(3) identification of all boilers and stationary gas turbines with a claimed exemption from the emission specifications of §117.105 or §117.107 of this title and the rule basis for the claimed exemption;

(4) identification of the election to use individual emission limits as specified in §117.105 of this title or the system-wide emission limit specified in §117.107 of this title to achieve compliance with this rule;

(5) a list of units to be controlled and the type of control to be applied for all such units, including an anticipated construction schedule;

(6) a list of any units which have been or will be retired, decommissioned, or shutdown and rendered inoperable, indicating the date of occurrence and whether these actions are a result of compliance with this regulation;

(7) the basis for calculation of the mass rate of NO_x emissions for each unit to demonstrate that each unit will achieve the NO_x emission rates specified in §117.105 or §117.107 of this title. Emissions from stationary gas turbines shall be represented in the units given by the appropriate emission limitation of §117.105 of this title; and

(8) for units required to install totalizing fuel flow meters in accordance with §117.113(e), (g), or (h) of this title (relating to Continuous Demonstration of Compliance), indication of whether the devices have been placed in operation by April 1, 1994.

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§117.111. Initial Demonstration of Compliance.

(a) All units which are subject to the emission limitations of §117.105 of this title (relating to Emission Specifications) or §117.107 of this title (relating to Alternative System-Wide Emission Specifications) shall be tested for nitrogen oxides (NO_x), carbon monoxide (CO), and oxygen (O_2) emissions. Units which inject urea or ammonia into the exhaust stream for NO_x control shall be tested for ammonia emissions. Such tests shall be performed in accordance with the schedules specified in §117.510(4) and (5) of this title (relating to Compliance Schedule For Utility Electric Generation).

(b) The tests required by subsection (a) of this section shall be used for determination of initial compliance with either the emission limits of §117.105 of this title or the assigned emission limits of §117.107 of this title, as applicable. Test results shall be reported in the units of the applicable emission limits and averaging periods.

(c) Continuous emissions monitoring systems (CEMS) required by §117.113(a) of this title (relating to Continuous Demonstration of Compliance) or predictive emissions monitoring systems (PEMS) required by §117.113(e) of this title shall be installed and operational prior to conducting initial demonstration of compliance testing under subsection (a) of this section. Verification of operational status shall, as a minimum, include completion of the manufacturer's written requirements or recommendations for installation, operation, and calibration of the device.

(d) Initial compliance with the emission specifications of §117.105 or §117.107 of this title for units operating with CEMS in accordance with §117.113(a) of this title or with PEMS in accordance with §117.113(e) of this title shall be demonstrated using the NO_x CEMS or PEMS as follows:

(1) To comply with the NO_x emission limit in pound per million (MM) Btu on a rolling 30-day average, NO_x emissions from a unit are monitored for 30 successive unit operating days and the 30-day average emission rate is used to determine compliance with the NO_x emission limit. The 30-day average emission rate is calculated as the average of all hourly emissions data recorded by the monitoring system during the 30-day test period.

(2) To comply with the NO_x emission limit in pound per MMBtu on a rolling 24-hour average, NO_x emissions from a unit are monitored for 24 consecutive operating hours and the 24-hour average emission rate is used to determine compliance with the NO_x emission limit. The 24-hour average emission rate is calculated as the average of all hourly emissions data recorded by the monitoring system during the 24-hour test period. Compliance with the NO_x emission limit for fuel oil firing shall be determined based on the first 24 consecutive operating hours a unit fires fuel oil.

(3) To comply with the NO_x emission limit in pounds per hour or parts per million by volume (ppmv) at 15% O_2 dry basis, on a block one-hour average, any one-hour period while operating at the maximum rated capacity, or as near thereto as practicable, after CEMS certification testing required in §117.113(b) of this title or PEMS certification testing required in §117.213(c) of this title (relating to Continuous Demonstration of Compliance) is used to determine compliance with the NO_x emission limit.

(4) To comply with the CO emission limit in ppmv on a rolling 24-hour average, CO emissions from a unit are monitored for 24 consecutive hours and the rolling 24-hour average emission rate is used to determine compliance with the CO emission limit. The rolling 24-hour average emission rate is calculated as the average of all hourly emissions data recorded by the monitoring system during the 24-hour test period.

Adopted 05/11/93 Effective 06/09/93

§117.113. Continuous Demonstration of Compliance.

(a) The owner or operator of each affected unit, as defined in §117.101 of this title (relating to Applicability), except for exempted units listed in §117.103 of this title (relating to Exemptions); peaking units as defined in §1.1 or §1.2 of Appendix E of 40 Code of Federal Regulations (CFR) Part 75, subject to the monitoring requirements of Appendix E; gas turbines monitored in accordance with subsection (f) of this section; and auxiliary boilers as defined in §117.10 of this title (relating to Definitions), monitored in accordance with subsection (d) of this section, shall install, calibrate, maintain, and operate an in-stack continuous emissions monitoring systems (CEMS) to measure nitrogen oxides (NO_x) on an individual basis. The CEMS shall be installed and operating by the time of compliance with the emission limits specified in §117.105 of this title (relating to Emission Specifications) or §117.107 of this title (relating to Alternative System-Wide Emission Specifications). Each CEMS shall be able to use measured exhaust or fuel flow rate data obtained by a certified flow meter and be capable of measuring the following:

(1) NO_x;

(2) carbon monoxide (CO); and

(3) oxygen (O_2) or carbon dioxide (CO_2) as a diluent.

(b) Any CEMS required by subsection (a) of this section shall be installed, calibrated, maintained, and operated in accordance with 40 CFR, Part 75 or 40 CFR, Part 60, as applicable. The Executive Director of the Texas Natural Resource Conservation Commission (TNRCC) may approve alternative locations to in-stack monitoring for any affected unit subject to this section.

(c) The owner or operator of each peaking unit as defined in 40 CFR Part 75, Appendix E §1.1 or §1.2, may monitor operating parameters for each unit in accordance with Appendix E and calculate NO_x emission rates based on those procedures or use CEMS in accordance with subsection (a) of this section to monitor NO_x emission rates.

(d) The owner or operator of each auxiliary boiler as defined in §117.010 of this title shall install, calibrate, maintain, and operate a CEMS in accordance with subsection (a) of this section or comply with the appropriate (considering boiler maximum rated capacity and annual heat input) industrial boiler monitoring requirements of §117.213 of this title (relating to Continuous Demonstration of Compliance).

(e) As an alternative to CEMS, the owner or operator of units subject to continuous monitoring requirements under this undesignated head (relating to Utility Electric Generation) may, with the approval of the Executive Director, elect to install, calibrate, maintain, and operate predictive emissions monitoring systems (PEMS) and totalizing fuel flow meters. The required PEMS and fuel flow meters shall be used to measure NO_x, CO, and O_2 (or CO_2) emissions and fuel flow for each affected unit and shall be used to demonstrate continuous compliance with the emission limitations of §117.105 or §117.107 of this title. As an alternative to using PEMS to monitor O_2 (or CO_2), subsection (a) of this section or similar alternative method approved by the Executive Director and the United States Environmental Protection Agency may be used. Any PEMS for units subject to the requirements of 40 CFR 75 shall meet the requirements of §117.119 of this title (relating to Notification, Recordkeeping, and Reporting Requirements) and 40 CFR 75 Subpart E, §§75.40 - 75.48. Any PEMS for units not subject to the requirements of 40 CFR 75 shall meet the requirements of §117.119 of this title and either 40 CFR 75, Subpart E, §§75.40 - 75.48 or §117.213(c)(1)-(3) of this title.

(f) The owner or operator of each gas turbine subject to the emission specifications of §117.105 of this title, in lieu of monitoring emissions in accordance with the monitoring requirements of 40 CFR 75, may elect to comply with the following monitoring requirements:

(1) for gas turbines rated less than 30 megawatt (MW) or peaking gas turbines (as defined in §117.10 of this title) which use steam or water injection to comply with the emission specifications of §117.105(h) or (i) of this title:

(A) install, calibrate, maintain and operate a CEMS or PEMS in compliance with subsection (b) of this section; or

(B) install, calibrate, maintain, and operate a continuous monitoring system to monitor and record the average hourly fuel and steam or water consumption. The system shall be accurate to within ± 5.0%. The steam-to-fuel or water-to-fuel ratio monitoring data shall constitute the method for demonstrating continuous compliance with the applicable emission specification of §117.105 of this title.

(2) for gas turbines subject to the emission specifications of §117.105(f) or (g) of this title, install, calibrate, maintain and operate a CEMS or PEMS in compliance with subsection (b) of this section.

(g) The owner or operator of any stationary gas turbine with a MW rating greater than or equal to 1.0 MW operated more than 850 hours per year (hr/yr) shall install and maintain totalizing fuel flow meters on an individual unit basis.

(h) The owner or operator of any utility boiler, steam generator, or auxiliary steam boiler using the exemption of §117.103(b)(2) of this title shall install and maintain totalizing fuel meters for each individual unit, as approved by the Executive Director, and record the annual fuel input for each unit, based on a rolling monthly average. The owner or operator of any stationary gas turbine using the exemption of §117.103(b)(3) of this title shall record the operating time with an elapsed run time meter approved by the Executive Director.

(i) The owner or operator of any utility boiler, steam generator, or auxiliary steam boiler using the exemption of §117.103(b)(2) of this title, or any stationary gas turbine using the exemption of §117.103(b)(3) of this title, shall notify the Executive Director within seven days if the Btu/yr or hr/yr limit specified in §117.103(b)(2) or §117.103(b)(3) of this title, as appropriate, is exceeded. If the Btu/yr or hr/yr limit, as appropriate, is exceeded, the exemption from the emission specifications of §117.105 of this title shall be permanently withdrawn. Within 90 days after loss of the exemption, the owner or operator shall submit a compliance plan detailing a plan to meet the applicable compliance limit as soon as possible, but no later than 24 months after exceeding the Btu/yr or hr/yr limit, as appropriate. Included with this compliance plan, the owner or operator shall submit a schedule of increments of progress for the installation of the required control equipment. This schedule shall be subject to the review and approval of the Executive Director.

(j) After the initial demonstration of compliance required by §117.111 of this title (relating to Initial Demonstration of Compliance), compliance with either §117.105 or §117.107 of this title, as applicable, shall be determined by the methods required in this section. Compliance with the emission limitations may also be determined at the discretion of the Executive Director using any TNRCC compliance method. If compliance with §117.105 of this title is selected, no unit subject to §117.105 of this title shall be operated at an emission rate higher than that allowed by the emission specifications of §117.105 of this title. If compliance with §117.107 of this title is selected, no unit subject to §117.107 of this title shall be operated at an emission rate higher than that approved by the Executive Director pursuant to §117.115(b)(2) of this title (relating to Final Control Plan Procedures).

Adopted 05/25/94 Effective 06/23/94

§117.115. Final Control Plan Procedures.

(a) For sources complying with §117.105 of this title (relating to Emission Specifications), the owner or operator of an affected source shall submit a final control report to show compliance with the requirements of §117.105 of this title by the date specified in §117.510(6) of this title (relating to Compliance Schedule For Utility Electric Generation). The report shall include a list of all affected units showing the method of control of nitrogen oxides (NO_x) emissions for each unit and the results of testing required in §117.111 of this title (relating to Initial Demonstration of Compliance).

(b) For sources complying with §117.107 of this title (relating to Alternative System-Wide Emission Specifications), the owner or operator of an affected source shall submit a final control plan to show attainment of the requirements of §117.107 of this title by the date specified in §117.510(6) of this title. The owner or operator shall:

(1) assign to each affected unit the maximum NO_x emission rate, expressed in units of pound per million (MM) Btu heat input on a rolling 24-hour average and rolling 30-day average for gaseous fuel firing, and a rolling 24-hour average for oil or coal firing, which are allowable for that unit under the requirements of §117.107 of this title;

(2) submit a list to the Executive Director for approval of the maximum allowable NO_x emission rates identified in paragraph (1) of this subsection and maintain a copy of the approved list for verification of continued compliance with the requirements of §117.107 of this title; and

(3) submit a description of the NO_x control method used to achieve compliance with §117.107 of this title, and the results of testing for each unit in accordance with the requirements of §117.111 of this title. For units complying with a pound per MMBtu emission limit on a rolling 30-day average, this information may be submitted according to the schedule given in §117.510(4) of this title.

(4) submit a list summarizing the results of testing for each unit in accordance with the requirements of §117.111 of this title.

Adopted 05/25/94 Effective 06/23/94

§117.117. Revision of Final Control Plan.

A revised final control plan may be submitted by the owner or operator, along with any required permit applications. Such a plan shall adhere to the emission limits and the final compliance dates of this undesignated head (relating to Utility Electric Generation). For sources complying with §117.105 of this title (relating to Emission Specifications), or §117.107 of this title (relating to Alternative System-Wide Emission Specifications), replacement new units may be included in the control plan. The revision of the final control plan shall be subject to the review and approval of the Executive Director.

Adopted 05/25/94 Effective 06/23/94

§117.119. Notification, Recordkeeping, and Reporting Requirements.

(a) For units subject to the exemptions allowed under §117.103(a) of this title (relating to Exemptions), hourly records shall be made of start-up and/or shutdown events and maintained for a period of at least two years. Records shall be available for inspection by the Texas Natural Resource Conservation Commission (TNRCC), the Unites States Environmental Protection Agency (EPA), and any local air pollution control agency having jurisdiction upon request. These records shall include, but are not limited to: type of fuel burned; quantity of each type fuel burned; gross and net energy production in megawatt-hours (MW-hr); and the date, time, and duration of the event.

(b) The owner or operator of a unit subject to the provisions of §117.105 of this title (relating to Emission Specifications) or §117.107 of this title (relating to Alternative System-Wide Emission Specifications) shall submit notification to the Executive Director as follows:

(1) verbal notification of the date of any initial demonstration of compliance testing conducted under §117.111 of this title (relating to Initial Demonstration of Compliance) at least 15 days prior to such date followed by written notification within 15 days after testing is completed; and

(2) verbal notification of the date of any continuous emissions monitoring systems (CEMS) or predictive emissions monitoring systems (PEMS) performance evaluation conducted under §117.113 of this title (relating to Continuous Demonstration of Compliance) at least 15 days prior to such date followed by written notification within 15 days after testing is completed.

(c) The owner or operator of an affected unit shall furnish the Executive Director and any local air pollution control agency having jurisdiction a copy of any initial demonstration of compliance testing conducted under §117.111 of this title or any CEMS or PEMS performance evaluation conducted under §117.113 of this title within 60 days after completion of such testing or evaluation. Such results shall be submitted in accordance with the appropriate compliance schedules specified in §117.510(3) and (4) of this title (relating to Compliance Schedule for Utility Electric Generation).

(d) The owner or operator of a unit required to install a CEMS, PEMS, or steam-to-fuel or water-to-fuel ratio monitoring system under §117.113 of this title shall report in writing to the Executive Director on a quarterly basis any exceedance of the applicable emission limitations in §117.105 or §117.107 of this title and the monitoring system performance. All reports shall be postmarked or received by the 30th day following the end of each calendar quarter. Written reports shall include the following information:

(1) the magnitude of excess emissions computed in accordance with 40 Code of Federal Regulations, Part 60, §60.13(h), any conversion factors used, the date and time of commencement and completion of each time period of excess emissions, and the unit operating time during the reporting period. For gas turbines using steam-to-fuel or water-to-fuel ratio monitoring to demonstrate compliance in accordance with §117.113(f)(1)(B) of this title, excess emissions are computed as each one-hour period during which the hourly steam-to-fuel or water-to-fuel ratio is less than the ratio determined to result in compliance during the initial demonstration of compliance test required by §117.111 of this title.

(2) specific identification of each period of excess emissions that occurs during start-ups, shutdowns, and malfunctions of the affected unit. The nature and cause of any malfunction (if known) and the corrective action taken or preventative measures adopted;

(3) the date and time identifying each period during which the continuous monitoring system was inoperative, except for zero and span checks and the nature of the system repairs or adjustments;

(4) when no excess emissions have occurred or the continuous monitoring system has not been inoperative, repaired, or adjusted, such information shall be stated in the report;

(5) if the total duration of excess emissions for the reporting period is less than 1.0% of the total unit operating time for the reporting period and the CEMS, PEMS, or steam-to-fuel or water-to-fuel ratio monitoring system downtime for the reporting period is less than 5.0% of the total unit operating time for the reporting period, only a summary report form (as outlined in the latest edition of the TNRCC "Guidance for Preparation of Summary, Excess Emission, and Continuous Monitoring System Reports")

shall be submitted, unless otherwise requested by the Executive Director of the TNRCC. If the total duration of excess emissions for the reporting period is greater than or equal to 1.0% of the total operating time for the reporting period or the CEMS or steam-to-fuel or water-to-fuel ratio monitoring system downtime for the reporting period is greater than or equal to 5.0% of the total operating time for the reporting period, a summary report and an excess emission report shall both be submitted.

(e) For units subject to the provisions of §117.105 or §117.107 of this title, records of hours of operation and other operating records shall be made and maintained for a period of at least two years. Records shall be available for inspection by the TNRCC, EPA, or local air pollution control agencies having jurisdiction upon request. Operating records for each unit shall be recorded and maintained at a frequency equal to the applicable emission specification averaging period, or monthly for units exempt from the emission specifications based on annual heat input, or hours of operation per calendar year, and shall include:

(1) emission rates in units of the applicable standards;

(2) gross energy production in MW-hr (not applicable to auxiliary boilers);

(3) quantity and type of fuel burned;

(4) the injection rate of reactant chemicals (if applicable); and

(5) CEMS, PEMS, or steam-to-fuel or water-to-fuel ratio monitoring system data, as applicable, pursuant to §117.113 of this title. The records shall include:

(A) the date, time, and duration of any malfunction in the operation of the monitoring system, except for zero and span checks, if applicable, and a description of system repairs and adjustments undertaken during each period;

(B) the results of initial certification testing, evaluations, calibrations, checks, adjustments, and maintenance of CEMS, PEMS, or steam-to-fuel or water-to-fuel ratio monitoring systems; and

(C) actual emissions or operating parameter measurements, as applicable.

(6) the results of performance testing, including initial demonstration of compliance testing conducted in accordance with §117.111 of this title.

Adopted 05/25/94 Effective 06/23/94

§117.121. Alternative Case Specific Specifications.

Where a person can demonstrate that an affected unit cannot attain the requirements of §117.105 of this title (relating to Emission Specifications), as applicable, the Executive Director, on a case-by-case basis after considering the technological and economic circumstances of the individual unit, may approve emission specifications different from §117.105 of this title for that unit based on the determination that such specifications are the result of the lowest emission limitation the unit is capable of meeting after the application of reasonably available control technology. In determining whether to approve alternative emission specifications, the Executive Director may take into consideration the ability of the plant at which the unit is located to meet emission specifications through system-wide averaging at maximum capacity. Any person affected by the decision of the Executive Director may appeal to the Commission by filing written notice of appeal with the Executive Director within 30 days after the decision. Such appeal is to be taken by written notification to the Executive Director. Section 103.71 of this title (relating to Request for Action by the Commission) should be consulted for the method of requesting Commission action on the appeal. Executive Director approval does not necessarily constitute satisfaction of all federal requirements nor eliminate the need for approval by EPA in cases where specified criteria for determining equivalency have not been clearly identified in applicable sections of this undesignated head (relating to Utility Electric Generation).

Adopted 05/25/94 Effective 06/23/94

SUBCHAPTER B : COMBUSTION AT EXISTING MAJOR SOURCES

COMMERCIAL, INSTITUTIONAL, AND INDUSTRIAL SOURCES

§117.201. Applicability.

The provisions of this undesignated head (relating to Commercial, Institutional, and Industrial Sources) shall apply to the following units located at any major stationary source of nitrogen oxides located within the Houston/Galveston or Beaumont/Port Arthur ozone nonattainment areas:

(1) commercial, institutional, or industrial boilers and process heaters with a maximum rated capacity of 40 million Btu per hour or greater;

(2) stationary gas turbines with a megawatt (MW) rating of 1.0 MW or greater; and

(3) stationary internal combustion engines which are:

(A) located in the Houston/Galveston ozone nonattainment area with a horsepower (hp) rating of 150 hp or greater; or

(B) located in the Beaumont/Port Arthur ozone nonattainment area with a horsepower rating of 300 hp or greater.

Adopted 05/11/93 Effective 06/09/93

§117.203. Exemptions.

(a) The provisions of §117.205 of this title (relating to Emission Specifications) or §117.207 of this title (relating to Alternative Plant-Wide Emission Specifications) shall not apply during periods of major upset or maintenance under the requirements of §101.6 of this title (relating to Notification Requirements for Major Upset), §101.7 of this title (relating to Notification Requirements for Maintenance), and §101.11 of this title (relating to Exemptions from Rules and Regulations).

(b) Units exempted from the provisions of this undesignated head (relating to Commercial, Institutional, and Industrial Sources), except for §117.209(c)(1) of this title (relating to Initial Control Plan Procedures) and §117.213(d)(2) and (g) of this title (relating to Continuous Demonstration of Compliance), include the following:

(1) any new units placed into service after November 15, 1992, except for new units which were placed into service as functionally identical replacement for existing units subject to the provisions of this undesignated head as of June 9, 1993. Any emission credits resulting from the operation of such replacement units shall be limited to the cumulative maximum rated capacity of the units replaced;

(2) any commercial, institutional, or industrial boiler or process heater with a maximum rated capacity of less than 40 million Btu per hour;

(3) any electric utility power generating boiler;

(4) flares, incinerators, fume abaters, sulfur recovery units, and sulfur plant reaction boilers;

(5) dryers, kilns, or ovens used for drying, baking, cooking, calcining, and vitrifying;

(6) stationary gas turbines and engines, which are:

(A) used in research and testing, or used for purposes of performance verification and testing, or used solely to power other engines or gas turbines during start-ups, or operated exclusively for firefighting and/or flood control, or used in response to and during the existence of any officially declared disaster or state of emergency, or used directly and exclusively by the owner or operator for agricultural operations necessary for the growing of crops or raising of fowl or animals, or used as chemical processing gas turbines; or

(B) demonstrated to operate less than 850 hours per year, based on a rolling 12-month average.

(7) stationary gas turbines with a megawatt (MW) rating of less than 1.0 MW; and

(8) stationary internal combustion engines which are:

(A) located in the Houston/Galveston ozone nonattainment area with a horsepower (hp) rating of less than 150 hp; or

(B) located in the Beaumont/Port Arthur ozone nonattainment area with a hp rating of less than 300 hp.

Adopted 05/25/94 Effective 06/23/94

§117.205. Emission Specifications.

(a) No person shall allow the discharge of air contaminants into the atmosphere to exceed the emission limits of this section, except as provided in §117.207 of this title (relating to Alternative Plant-Wide Emission Specifications), or §117.223 of this title (relating to Source Cap).

(1) For purposes of this subchapter, the lower of any permit nitrogen oxides (NO_x) emission limit in effect on June 9, 1993 under a permit issued pursuant to Chapter 116 of this title (relating to Control of Air Pollution by Permits for New Construction or Modification) and the emission limits of subsections (b)-(d) of this section shall apply, except that:

(A) gas-fired boilers and process heaters operating under a permit issued after March 3, 1982, with an emission limit of 0.12 pound NO_x per million (MM) Btu heat input, shall be limited to that rate for the purposes of this subchapter; and

(B) gas-fired boilers and process heaters which have had NO_x reduction projects permitted since November 15, 1990 and prior to June 9, 1993 that were solely for the purpose of making early NO_x reductions, shall be subject to the appropriate emission limit of subsection (b) of this section. The affected person shall document that the NO_x reduction project was solely for the purpose of obtaining early reductions, and include this documentation in the initial control plan required in §117.209 of this title (relating to Initial Control Plan Procedures).

(2) For purposes of calculating NO_x emission limitations under this section from existing permit limits, the following procedure shall be used:

(A) the limit explicitly stated in pound NO_x per MMBtu of heat input by permit provision (converted from low heating value to high heating value, as necessary); or

(B) the NO_x emission limit is the limit calculated as the permit Maximum Allowable Emission Rate Table emission limit in pounds per hour, divided by the maximum heat input to the unit in MMBtu per hour (MMBtu/hr), as represented in the permit application. In the event the maximum heat input to the unit is not explicitly stated in the permit application, the rate shall be calculated from Table 6 of the permit application, using the design maximum fuel flow rate and higher heating value of the fuel, or, if neither of the above are available, the unit's nameplate heat input.

(3) For any unit placed into service after June 9, 1993 and prior to May 31, 1995 or the final compliance date as approved under the provisions of §117.540 of this title (relating to Phased Reasonably Available Control Technology (RACT)), as functionally identical replacement for an existing unit or group of units subject to the provisions of this chapter, the higher of any permit NO_x emission limit under a permit issued after June 9, 1993 pursuant to Chapter 116 of this title and the emission limits of subsections (b)-(d) of this section shall apply. Any emission credits resulting from the operation of such replacement units shall be limited to the cumulative maximum rated capacity of the units replaced. The inclusion of such new units is an optional method for complying with the emission limitations of §117.207 or §117.223 of this title. Compliance with this paragraph does not eliminate the requirement for new units to comply with Chapter 116 of this title.

(b) For boilers and process heaters which operate with continuous emission monitors in accordance with §117.213(b) of this title (relating to Continuous Demonstration of Compliance), or with predictive emissions monitors in accordance with §117.213(c) of this title, the emission limits shall apply as the mass of NO_x emitted per unit of energy input (pound NO_x per MMBtu), on a rolling 30-day average period, or as the mass of NO_x emitted per hour (pounds per hour), on a block one-hour average. For boilers and process heaters which do not operate with continuous or predictive emission monitors, the emission limits shall apply as the mass of NO_x emitted per hour (pounds NO_x per hour), on a block one-hour average. The mass of NO_x emitted per hour shall be calculated as the product of the boiler's or process heater's maximum rated capacity and its applicable limit in pound NO_x per MMBtu. For each commercial, institutional, or industrial boiler and process heater with a maximum rated capacity greater than or equal to 100.0 MMBtu/hr of heat input, the applicable emission limit is as follows:

(1) gas-fired boilers, as follows:

(A) low heat release boilers with no preheated air or preheated air less than 200°F, 0.10 pound (lb) NO_x/MMBtu of heat input;

(B) low heat release boilers with preheated air greater than or equal to 200°F and less than 400°F, 0.15 lb NO_x/MMBtu of heat input;

(C) low heat release boilers with preheated air greater than or equal to 400°F, 0.20 lb NO_x/MMBtu of heat input;

(D) high heat release boilers with no preheated air or preheated air less than 250°F, 0.20 lb NO_x/MMBtu of heat input;

(E) high heat release boilers with preheated air greater than or equal to 250°F and less than 500°F, 0.24 lb NO_x/MMBtu of heat input; or

(F) high heat release boilers with preheated air greater than or equal to 500°F, 0.28 lb NO_x/MMBtu of heat input.

(2) gas-fired process heaters, based on either air preheat temperature or firebox temperature, as follows:

(A) based on air preheat temperature:

(i) process heaters with preheated air less than 200°F, 0.10 lb NO_x/MMBtu of heat input;

(ii) process heaters with preheated air greater than or equal to 200°F and less than 400°F, 0.13 lb NO_x/MMBtu of heat input; or

(iii) process heaters with preheated air greater than or equal to 400°F, 0.18 lb NO_x/MMBtu of heat input.

(B) based on firebox temperature:

(i) process heaters with a firebox temperature less than 1,400°F, 0.10 lb NO_x/MMBtu of heat input;

(ii) process heaters with a firebox temperature greater than or equal to 1,400°F and less than 1,800°F, 0.125 lb NO_x/MMBtu of heat input; or

(iii) process heaters with a firebox temperature greater than or equal to 1,800°F, 0.15 lb NO_x/MMBtu of heat input;

(3) liquid fuel-fired boilers and process heaters, 0.30 lb NO_x/MMBtu of heat input;

(4) wood fuel-fired boilers and process heaters, 0.30 lb NO_x/MMBtu of heat input;

(5) any unit operated with a combination of gaseous, liquid, or wood fuel, a variable emission limit calculated as the heat input weighted average of the applicable emission limits of this subsection.

(6) for any gas-fired boiler or process heater firing gaseous fuel which contains more than 50% hydrogen by volume, over an eight-hour period, in which the fuel gas composition is sampled and analyzed every three hours, a multiplier of 1.25 times the appropriate emission limit in this subsection may be used for that eight-hour period. The total hydrogen volume in all gaseous fuel streams will be divided by the total gaseous fuel flow volume to determine the volume percent of hydrogen in the fuel supply.

(c) No person shall allow the discharge into the atmosphere from any stationary gas turbine with a MW rating greater than or equal to 10.0 MW, emissions in excess of a block one-hour average concentration of 42 parts per million by volume (ppmv) NO_x and 132 ppmv carbon monoxide (CO) at 15% oxygen (O_2), dry basis.

(d) No person shall allow the discharge into the atmosphere from any gas-fired, rich-burn, stationary, reciprocating internal combustion engine, emissions in excess of a block one-hour average of 2.0 grams NO_x per horsepower hour (g NO_x/hp-hr) and 3.0 g CO/hp-hr for engines which are:

(1) rated 150 hp or greater and located in the Houston/Galveston ozone nonattainment area; or

(2) rated 300 hp or greater and located in the Beaumont/Port Arthur ozone nonattainment area.

(e) No person shall allow the discharge into the atmosphere from any boiler or process heater subject to NO_x emission specifications in subsection (a) or (b) of this section, CO emissions in excess of the following limitations, based on a block one-hour average:

(1) for gas or liquid fuel-fired boilers or process heaters, 400 ppmv at 3% O_2, dry basis; or

(2) for wood fuel-fired boilers or process heaters, 775 ppmv at 7% O_2, dry basis.

(f) No person shall allow the discharge into the atmosphere from any unit subject to a NO_x emission limit in this undesignated head (relating to Commercial, Institutional, and Industrial Sources), ammonia emissions in excess of 20 ppmv based on a block one-hour averaging period.

(g) Units exempted from the emissions specifications of this section include the following:

(1) any commercial, institutional, or industrial boiler or process heater with a maximum rated capacity less than 100 MMBtu/hr;

(2) any low annual capacity factor boiler, process heater, stationary gas turbine, or stationary internal combustion engine as defined in §117.10 of this title (relating to Definitions);

(3) boilers and industrial furnaces which are regulated as existing facilities by the United States Environmental Protection Agency at 40 Code of Federal Regulations Part 266, Subpart H;

(4) fluid catalytic cracking units (including CO boilers);

(5) supplemental waste heat recovery units used in turbine exhaust ducts;

(6) any lean-burn, stationary, reciprocating internal combustion engine; and

(7) any stationary gas turbine with a MW rating less than 10.0 MW.

(h) The NO_x emission limits specified in subsections (a)-(d) of this section shall apply at all times except as specified in §117.203 of this title (relating to Exemptions), §117.207 of this title, and §117.223 of this title. The CO emission limits specified in subsections (c), (d), and (e) of this section and the ammonia emission limits specified in subsection (f) of this section shall apply at all times, except as specified in §117.203 of this title.

Adopted 05/25/94 Effective 06/23/94

§117.207. Alternative Plant-Wide Emission Specifications.

(a) An owner or operator may achieve compliance with the emission limits of §117.205 of this title (relating to Emission Specifications) by achieving equivalent nitrogen oxides (NO_x) emission reductions obtained by compliance with a plant-wide emission limitation. Any owner or operator who elects to comply with a plant-wide emission limit shall reduce emissions of NO_x from affected units so that if all such units were operated at their maximum rated capacity, the plant-wide emission rate of NO_x from these units would not exceed the plant-wide emission limit as defined in §117.10 of this title (relating to Definitions) and shall establish an enforceable emission limit for each affected unit at the source. For boilers and process heaters which operate with continuous emission monitors in accordance with §117.213(b) of this title (relating to Continuous Demonstration of Compliance), or with predictive emission monitors in accordance with §117.213(c) of this title, the emission limits shall apply as the mass of NO_x emitted per unit of energy input (pound NO_x per million (MM) Btu), on a rolling 30-day average period, or as the mass of NO_x emitted per hour (pounds per hour), on a block one-hour average. For boilers and process heaters which do not operate with continuous or predictive emission monitors, the emission limits shall apply as the mass of NO_x emitted per hour (pounds NO_x per hour), on a block one-hour average. For stationary gas turbines, the emission limits shall apply as the concentration in parts per million by volume (ppmv) at 15% oxygen (O_2), dry basis on a block one-hour average. For stationary internal combustion engines, the emission limits shall apply in units of grams per horsepower-hour (hp-hr) on a block one-hour average.

(b) Units exempted from emission specifications in accordance with §117.205(g) of this title are also exempt under this section and shall not be included in the plant-wide emission limit, except as provided in subsection (f) of this section.

(c) An owner or operator of any gaseous and liquid fuel-fired unit which derives more than 50% of its annual heat input from gaseous fuel shall use only the appropriate gaseous fuel emission limit of §117.205 of this title at maximum rated capacity in calculating the plant-wide emission limit and shall assign to the unit the maximum allowable NO_x emission rate while firing gas, calculated in accordance with subsection (a) of this section. The owner or operator shall also:

(1) comply with the assigned maximum allowable emission rate while firing gas only;

(2) comply with the liquid fuel emission limit of §117.205 of this title while firing liquid fuel only; and

(3) comply with a limit calculated as the actual heat input weighted sum of the assigned gas-firing allowable emission rate and the liquid fuel emission limit of §117.205 of this title while operating on liquid and gaseous fuel concurrently.

(d) An owner or operator of any gaseous and liquid fuel-fired unit which derives more than 50% of its annual heat input from liquid fuel shall use a heat input weighted average of the appropriate gaseous and liquid fuel emission specifications of §117.205 of this title in calculating the plant-wide emission limit and shall assign to the unit the maximum allowable NO_x emission rate, calculated in accordance with subsection (a) of this section.

(e) An owner or operator of any unit operated with a combination of gaseous (or liquid) and solid fuels shall use a heat input weighted average of the appropriate emission specifications of §117.205 of this title in calculating the plant-wide emission limit and shall assign to the unit the maximum allowable NO_x emission rate, calculated in accordance with subsection (a) of this section.

(f) The owner or operator of exempted units as defined in §117.205(g) of this title may elect to include one or more of an entire equipment class of exempted units into the alternative plant-wide emission specifications as defined in this section. The equipment classes which may be included in the alternative plant-wide emission specifications as an entire population of units at the major source include the following: fluid catalytic cracking unit carbon monoxide (CO) boilers; lean-burn, gas-fired, stationary, reciprocating internal combustion engines rated 150 hp or greater; boilers, steam generators, or process heaters with a maximum rated capacity of greater than or equal to 40 MMBtu per hour (MMBtu/hr) and less than 100 MMBtu/hr; stationary gas turbines with a megawatt (MW) rating of greater than or equal to 1.0 MW and less than 10.0 MW; and boilers and industrial furnaces which are regulated as existing facilities by the United States Environmental Protection Agency (EPA) at 40 Code of Federal Regulations (CFR) Part 266, Subpart H. Low annual capacity factor boilers, process heaters, gas turbines, or engines as defined in §117.10 of this title are not to be considered as part of that class of equipment. The individual emission limits that are to be used in calculating the alternative plant-wide emission specifications are the lower of the emission specifications determined in accordance with §117.205(a) of this title and the following, as applicable:

(1) fluid catalytic cracking unit CO boilers, 50% NO_x reduction across the inlet of the CO boiler to the outlet of the CO boiler, with the outlet concentration in ppmv converted into a pound (lb) NO_x/MMBtu of heat input;

(2) lean-burn, gas-fired, stationary, reciprocating internal combustion engines rated 150 hp or greater, 5.0 grams NO_x hp-hr (g NO_x/hp-hr) under all operating conditions;

(3) boilers, steam generators, or process heaters with a maximum rated capacity of greater than or equal to 40 MMBtu/hr and less than 100 MMBtu/hr, the emission specifications in §117.205(a) of this title for the applicable type of unit; and

(4) stationary gas turbines with a MW rating of greater than or equal to 1.0 MW and less than 10.0 MW, 42 ppmv NO_x at 15% O_2, dry basis.

(5) boilers and industrial furnaces which are regulated as existing facilities by EPA at 40 CFR Part 266, Subpart H, the appropriate emission limitation in §117.205(b) of this title.

(g) Solely for the purposes of calculating the plant-wide emission limit, the allowable mass emission rate for each affected unit shall be calculated from the emission specifications of §117.205 of this title, as follows.

(1) The NO_x emission rate (in pounds per hour) for each affected boiler and process heater is the product of its maximum rated capacity and its NO_x emission specification of §117.205 of this title.

(2) The NO_x emission rate (in pounds per hour) for each affected stationary internal combustion engine is the product of the applicable NO_x emission specification of §117.205 of this title (expressed in g/hp-hr) and the engine manufacturer's rated heat input (expressed in MMBtu/hr) at the engine's hp rating; divided by the product of the engine manufacturer's rated heat rate (expressed in Btu/hp-hr) at the engine's hp rating and $454(10^6)$.

(3) The NO_x emission rate (in pounds per hour) for each affected stationary gas turbine is the product of the in-stack NO_x, the turbine manufacturer's rated exhaust flow rate (expressed in pounds per hour at MW rating and International Standards Organization (ISO) flow conditions) and $(46/28)(10^{-6})$;

Where:

In-stack NO_x = NO_x(allowable) x (1 - $\%H_2O$/100) x [20.9 - $\%O_2$/ (1 - $\%H_2O$/100)]/5.9

NO_x (allowable) = the applicable NO_x emission specification of §117.205(c) of this title (expressed in ppmv NO_x at 15% O_2, dry basis).

$\%H_2O$ = the volume percent of water in the stack gases, as calculated from the manufacturer's data, or other data as approved by the Executive Director, at MW rating and ISO flow conditions.

$\%O_2$ = the volume percent of O_2 in the stack gases on a wet basis, as calculated from the manufacturer's data, or other data as approved by the Executive Director, at MW rating and ISO flow conditions.

(4) The NO_x emission rate (in pounds per hour) for each affected gas-fired boiler and process heater firing gaseous fuel which contains more than 50% hydrogen (H_2) by volume, over an annual basis, in which the fuel gas composition is sampled and analyzed every three hours, may use a multiplier of 1.25 times the product of its maximum rated capacity and its NO_x emission specification of §117.205 of this title. Double application of the H_2 content multiplier using this paragraph and §117.205(b)(6) of this title is not allowed.

(h) The owner or operator of any gas-fired boiler or process heater firing gaseous fuel which contains more than 50% H_2 by volume, over an eight-hour period, in which the fuel gas composition is sampled and analyzed every three hours, may use a multiplier of 1.25 times the emission limit assigned to the unit in this section for that eight-hour period, not applicable to units under paragraph (g)(4) of this section. The total H_2 volume in all gaseous fuel streams will be divided by the total gaseous fuel flow volume to determine the volume percent of H_2 in the fuel supply.

Adopted 05/25/94 Effective 06/23/94

§117.208. Operating Requirements.

(a) Except during major upset or maintenance as referenced in §101.6 of this title (relating to Notification Requirements for Major Upset), §101.7 of this title (relating to Notification Requirements for Maintenance), and §101.11 of this title (relating to Exemptions from Rules and Regulations), the owner or operator shall operate any unit subject to the emission limitations of §117.205 of this title (relating to Emission Specifications) in compliance with those limitations.

(b) The owner or operator shall operate any unit subject to the plant-wide emission limit of §117.207 of this title (relating to Alternative Plant-Wide Emission Specifications) such that the assigned maximum nitrogen oxides (NO_x) emission rate for each unit expressed in units of the applicable emission limit and averaging period, is in accordance with the list approved by the Executive Director pursuant to §117.215 of this title (relating to Final Control Plan Procedures).

(c) The owner or operator shall operate any unit subject to the source cap emission limits of §117.223 of this title (relating to Source Cap) in compliance with those limitations.

(d) All units subject to the emission limitations of §117.205, §117.207, or §117.223 of this title shall be operated so as to minimize NO_x emissions, consistent with the emission control techniques selected, over the unit's operating or load range during normal operations. Such operational requirements include the following.

(1) Each boiler shall be operated with oxygen (O_2) or carbon monoxide (CO) trim (or both).

(2) Each boiler and process heater controlled with forced flue gas recirculation (FGR) to reduce NO_x emissions shall be operated such that the proportional design rate of FGR is maintained, consistent with combustion stability, over the operating range.

(3) Each boiler and process heater controlled with induced draft FGR to reduce NO_x

emissions shall be operated such that the operation of FGR over the operating range is not restricted by artificial means.

(4) Each unit controlled with steam or water injection shall be operated such that injection rates are maintained to limit NO_x concentrations to less than or equal to the NO_x concentrations achieved at maximum rated capacity (corrected to 15% O_2 on a dry basis for gas turbines).

(5) Each unit controlled with post combustion control techniques shall be operated such that the reducing agent injection rate is maintained to limit NO_x concentrations to less than or equal to the NO_x concentrations achieved at maximum rated capacity.

(6) Each stationary internal combustion engine controlled with nonselective catalytic reduction shall be equipped with an automatic air-fuel ratio (AFR) controller which operates on exhaust O_2 or CO control and maintains AFR in the range required to meet the engine's applicable emission limits.

(7) Each stationary internal combustion engine shall be checked for proper operation of the engine by recorded measurements of NO_x and CO emissions at least quarterly and as soon as practicable after each occurrence of engine maintenance which may reasonably be expected to increase emissions, O_2 sensor replacement, or catalyst cleaning or catalyst replacement. Stain tube indicators specifically designed to measure NO_x concentrations shall be acceptable for this documentation, provided a hot air probe or equivalent device is used to prevent error due to high stack temperature, and three sets of concentration measurements are made and averaged. Portable NO_x analyzers shall also be acceptable for this documentation.

Adopted 05/25/94 Effective 06/23/94

§117.209. Initial Control Plan Procedures.

(a) The owner or operator of any major source of nitrogen oxides (NO_x) shall submit, for the approval of the Executive Director, an initial control plan for installation of NO_x emissions control equipment (if required in order to comply with the emission specifications of this subchapter) and demonstration of anticipated compliance with the applicable requirements of this subchapter. The Executive Director shall approve the plan if it contains all the information specified in this section. Revisions to the initial control plan shall be submitted with the final control plan.

(b) The owner or operator shall provide results of emissions testing using portable or reference method analyzers or, as available, initial demonstration of compliance testing conducted in accordance with §117.211(e) or (f) of this title (relating to Initial Demonstration of Compliance) for NO_x, carbon monoxide (CO), and oxygen emissions while firing gaseous fuel (and as applicable, hydrogen (H_2) fuel for units which may fire more than 50% H_2 by volume) and liquid and/or solid fuel at the maximum rated capacity or as near thereto as practicable, for the units listed in this subsection. Previous testing documentation for any claimed test waiver as allowed by §117.211(d) of this title shall be submitted with the initial control plan. Any units which were not operated between June 9, 1993 and April 1, 1994 and do not have earlier representative emission test results available shall be tested and the results submitted to the Texas Natural Resource Conservation Commission (TNRCC), with certification of the equipment's shutdown period, within 90 days after the date such equipment is returned to operation. Test results are required for the following units:

(1) boilers and process heaters with a maximum rated capacity greater than or equal to 40.0 million Btu per hour (MMBtu/hr), except for low annual capacity factor boilers and process heaters as defined in §117.10 of this title (relating to Definitions);

(2) boilers and industrial furnaces with a maximum rated capacity greater than or equal to 40.0 MMBtu/hr which are regulated as existing facilities by the United States Environmental Protection Agency (EPA) at 40 Code of Federal Regulations, Part 266, Subpart H, except for low annual capacity factor boilers and process heaters as defined in §117.10 of this title;

(3) fluid catalytic cracking units with a maximum rated capacity greater than or equal to 40 MMBtu/hr;

(4) gas turbine supplemental waste heat recovery units with a maximum rated fired capacity greater than or equal to 40 MMBtu/hr, except for low annual capacity factor gas turbine supplemental waste heat recovery units as defined in §117.10 of this title;

(5) stationary gas turbines with a megawatt (MW) rating of greater than or equal to 1.0 MW, except for low annual capacity factor gas turbines or peaking gas turbines as defined in §117.10 of this title; and

(6) gas-fired, stationary, reciprocating internal combustion engines which are located in the Houston/Galveston ozone nonattainment area and rated 150 horsepower (hp) or greater, or located in the Beaumont/Port Arthur ozone nonattainment area and rated 300 hp or greater, except for low annual capacity factor engines or peaking engines as defined in §117.10 of this title.

(c) The initial control plan shall be submitted in accordance with the schedule specified in §117.520(1) of this title (relating to Compliance Schedule For Commercial, Institutional, and Industrial Combustion Sources) and shall contain the following:

(1) a list of all combustion units at the source with a maximum rated capacity greater than 5.0 MMBtu/hr; all stationary, reciprocating internal combustion engines which are located in the Houston/Galveston ozone nonattainment area and rated 150 hp or greater, or located in the Beaumont/ Port Arthur ozone nonattainment area and rated 300 hp or greater; all stationary gas turbines with a MW rating of greater than or equal to 1.0 MW; to include the maximum rated capacity, anticipated annual capacity factor, the facility identification numbers and emission point numbers as submitted to the Emissions Inventory Section of the TNRCC, and the emission point numbers as listed on the Maximum Allowable Emissions Rate Table of any applicable TNRCC permit for each unit;

(2) identification of all units subject to the emission specifications of §117.205 of this title (relating to Emission Specifications), §117.207 of this title (relating to Alternative Plant-Wide Emission Specifications), or §117.223 of this title (relating to Source Cap);

(3) identification of all boilers, process heaters, stationary gas turbines, or engines with a

claimed exemption from the emission specifications of §117.205 or §117.207 of this title and the rule basis for the claimed exemption;

(4) identification of the election to use individual emission limits as specified in §117.205 of this title, the plant-wide emission limit as specified in §117.207 of this title, or the source cap emission limit as specified in §117.223 of this title to achieve compliance with this rule;

(5) a list of units to be controlled and the type of control to be applied for all such units, including an anticipated construction schedule;

(6) a list of units requiring operating modifications to comply with §117.208(d) of this title (relating to Operating Requirements) and the type of modification to be applied for all such units, including an anticipated construction schedule;

(7) a list of any units which have been or will be retired, decommissioned, or shutdown and rendered inoperable after November 15, 1990 as a result of compliance with this regulation, indicating the date of occurrence or anticipated date of occurrence;

(8) the basis for calculation of the rate of NO_x emissions for each unit to demonstrate that each unit will achieve the NO_x emission rates specified in §117.205, §117.207, or §117.223 of this title. For fluid catalytic cracking unit CO boilers, the basis for calculation of the pound NO_x per million Btu (lb NO_x/MMBtu) rate for each unit shall include the following:

(A) the calculation of the CO boiler heat input;

(B) the calculation of the appropriate CO boiler volumetric inlet and exhaust flowrates; and

(C) the calculation of the CO boiler lb NO_x/MMBtu emission rate;

(9) for units required to install totalizing fuel flow meters in accordance with §117.213(a)-(e) of this title (relating to Continuous Demonstration of Compliance), indication of whether the devices are currently in operation, and if so, whether they have been installed as a result of the requirements of this chapter;

(10) for units which have had NO_x reduction projects as specified in §117.205(a)(1)(B) of this title, documentation that such projects were undertaken solely for the purpose of obtaining early NO_x reductions; and

(11) test results in accordance with subsection (b) of this section.

Adopted 05/25/94 Effective 06/23/94

§117.211. Initial Demonstration of Compliance.

(a) All units which are subject to the emission limitations of §117.205 of this title (relating to Emission Specifications), §117.207 of this title (relating to Alternative Plant-Wide Emission Specifications), or §117.223 of this title (relating to Source Cap), and all units belonging to equipment classes which are elected to be included in the alternative plant-wide emission specifications as defined in §117.207(f) of this title, or in the source cap as defined in §117.223(b)(4) of this title, shall be tested for nitrogen oxides (NO_x), carbon monoxide (CO), and oxygen (O_2) emissions while firing gaseous fuel (and as applicable, hydrogen (H_2) fuel for units which may fire more than 50% H_2 by volume), and liquid and solid fuel. Units which inject urea or ammonia into the exhaust stream for NO_x control shall be tested for ammonia emissions. Initial demonstration of compliance testing of these units shall be performed in accordance with the schedule specified in §117.520 of this title (relating to Compliance Schedule For Commercial, Institutional, and Industrial Combustion Sources).

(b) The initial demonstration of compliance tests required by subsection (a) of this section shall use the test methods referenced in subsection (e) or (f) of this section and shall be used for determination of initial compliance with either the emission limits of §117.205 of this title, the assigned emission limits of §117.207 of this title, or §117.223 of this title, as applicable. Test results shall be reported in the units of the applicable emission limits and averaging periods.

(c) Any continuous emissions monitoring system (CEMS) required by §117.213(b) of this title (relating to Continuous Demonstration of Compliance) or any predictive emissions monitoring system (PEMS) approved for use in lieu of CEMS in accordance with §117.213(c) of this title shall be installed and operational prior to conducting initial demonstration of compliance testing under subsection (a) of this section. Verification of operational status shall, as a minimum, include completion of the manufacturer's written requirements or recommendations for installation, operation, and calibration of the device or system.

(d) Testing conducted prior to the effective date of this rule may be used to demonstrate compliance with the standards specified in §117.205, §117.207, or §117.223 of this title, or to satisfy the testing requirements of §117.209(b) of this title (relating to Initial Control Plan Procedures), if the owner or operator of an affected facility demonstrates to the Executive Director that the prior demonstration of compliance testing at least meets the requirements of subsections (a), (b), (c), (e), and (f) of this section. The Executive Director reserves the right to request demonstration of compliance testing or CEMS or PEMS performance evaluation at any time.

(e) Compliance with the emission specifications of §117.205, §117.207, or §117.223 of this title for units operating without CEMS or PEMS shall be demonstrated while operating at the maximum rated capacity, or as near thereto as practicable. Compliance shall be determined by the average of three one-hour emission test runs, using the following test methods:

(1) Test Method 7E or 20 (40 Code of Federal Regulations (CFR), Part 60, Appendix A) for NO_x;

(2) Test Method 10, 10A, or 10B (40 CFR 60, Appendix A) for CO;

(3) Test Method 3A or 20 (40 CFR 60, Appendix A) for O_2;

(4) Test Method 2 (40 CFR 60, Appendix A) for exhaust gas flow and following the measurement site criteria of Test Method 1, Section 2.1 (40 CFR 60, Appendix A), or Test Method 19 (40 CFR 60, Appendix A) for exhaust gas flow in conjunction with the measurement site criteria of Performance Specification 2, Section 3.2 (40 CFR 60, Appendix B);

(5) American Society of Testing and Materials (ASTM) Method D1945-91 or ASTM Method D3588-93 for fuel composition; ASTM Method D1826-88 or ASTM Method D3588-91 for calorific value; or alternate methods as approved by the Executive Director and the United States Environmental Protection Agency (EPA); or

(6) EPA-approved alternate test methods or minor modifications to these test methods as approved by the Executive Director, as long as the minor modifications meet the following conditions:

(A) the change does not affect the stringency of the applicable emission limitation; and

(B) the change affects only a single source or facility application.

(f) Initial compliance with the emission specifications of §117.205 or §117.207 of this title for units operating with CEMS in accordance with 117.213(b) of this title, or PEMS in accordance with 117.213(c) of this title, shall be demonstrated using the CEMS or PEMS as follows:

(1) For boilers and process heaters complying with a NO_x emission limit in pound per million Btu on a rolling 30-day average, NO_x emissions from the unit are monitored for 30 successive unit operating days and the 30-day average emission rate is used to determine compliance with the NO_x emission limit. The 30-day average emission rate is calculated as the average of all hourly emissions data recorded by the monitoring system during the 30-day test period.

(2) For boilers, process heaters, and gas turbines complying with a NO_x emission limit in pounds per hour or parts per million by volume at 15% O_2, dry basis, on a block one-hour average, any one-hour period while operating at the maximum rated capacity, or as near thereto as practicable, after CEMS certification testing required in §117.213(b) of this title or PEMS certification testing required in §117.213(c) of this title is used to determine compliance with the NO_x emission limit.

(3) For units complying with a CO emission limit, block one-hour average, any one-hour period after CEMS certification testing required in §117.213(b) of this title or PEMS certification testing required in §117.213(c) of this title is used to determine compliance with the CO emission limit.

Adopted 05/25/94 Effective 06/23/94

§117.213. Continuous Demonstration of Compliance.

(a) The owner or operator of units listed in this subsection and subject to the provisions of this undesignated head (relating to Commercial, Institutional, and Industrial Sources) shall install, calibrate, maintain, and operate an oxygen (O_2) monitor to measure exhaust O_2 concentration and a totalizing fuel flow meter to measure the fuel usage (for natural gas, refinery or process fuel gas, and fuel oil streams). The O_2 monitors and totalizing fuel flow meters shall be installed and operating by the time of compliance with the emission limits specified in §117.205 of this title (relating to Emission Specifications) or §117.207 of this title (relating to Alternative Plant-Wide Emission Specifications) for the following units:

(1) each commercial, institutional, and industrial boiler with a rated heat input greater than or equal to 100 million Btu per hour (MMBtu/hr) and less than 250 MMBtu/hr and an annual heat input greater than $2.2(10^{11})$ Btu per year (Btu/yr); and

(2) each process heater with a rated heat input greater than or equal to 100 MMBtu/hr and less than 200 MMBtu/hr and an annual heat input greater than $2.2(10^{11})$ Btu/yr.

(b) The owner or operator of units listed in this subsection and subject to the provisions of this undesignated head shall install, calibrate, maintain, and operate a continuous exhaust nitrogen oxides (NO_x) monitor, a carbon monoxide (CO) monitor, an O_2 (or carbon dioxide (CO_2)) diluent monitor, and a totalizing fuel flow meter (for natural gas, refinery or process fuel gas, and fuel oil streams). The required continuous emissions monitoring systems (CEMS) and fuel flow meters will be used to measure NO_x, CO, and O_2 (or CO_2) emissions and fuel flow for each affected unit. One CEMS may be used to monitor up to three units. Any CEMS shall meet all the requirements of 40 Code of Federal Regulations (CFR), Part 60, §60.13; 40 CFR 60, Appendix B, Performance Specifications 2, 3, and 4; and quality assurance procedures of 40 CFR 60, Appendix F, except that a cylinder gas audit may be performed in lieu of the annual relative accuracy test audit required in Section 5.1.1. The CEMS shall be subject to the approval of the Executive Director of the Texas Natural Resource Conservation Commission (TNRCC) under any permit issued pursuant to Title V of the 1990 Federal Clean Air Act Amendments.

(1) The CEMS shall be installed by the time of compliance with the emission limits specified in §117.205 or §117.207 of this title for the following units:

(A) each commercial, institutional, and industrial boiler with a rated heat input greater than or equal to 250 MMBtu/hr and an annual heat input greater than $2.2(10^{11})$ Btu/yr;

(B) each process heater with a rated heat input greater than or equal to 200 MMBtu/hr and an annual heat input greater than $2.2(10^{11})$ Btu/yr;

(C) each stationary gas turbine with a megawatt (MW) rating greater than or equal to 30 MW operated more than 850 hours per year;

(D) each unit which uses a chemical reagent for reduction of NO_x; and

(E) each unit for which the owner or operator elects to comply with the NO_x emission specifications of §117.205 or §117.207 of this title using a pound per MMBtu limit on a 30-day rolling average.

(2) The units listed in §117.205(g)(3)-(5) of this title are not required to install CEMS under this subsection.

(3) Gas turbines or other units which are affected units and are subject to continuous emissions monitoring requirements in accordance with 40 CFR 75 shall comply with those requirements in lieu of complying with the 40 CFR 60 requirements of this section.

(c) As an alternative to CEMS, the owner or operator of units subject to continuous monitoring requirements under this undesignated head may, with the approval of the Executive Director, elect to install, calibrate, maintain, and operate predictive emissions monitoring systems (PEMS) and totalizing fuel flow meters (for natural gas, refinery or process fuel gas, and fuel oil streams). The required PEMS and fuel flow meters may be used to predict any or all of the variables of NO_x, CO, and O_2 (or CO_2) emissions and fuel flow for each affected unit and shall be used to demonstrate continuous compliance with the emission limitations of §117.205 and §117.207 of this title or §117.223 of this title (relating to Source Cap) as applicable. CEMS shall be used to monitor any of the variables of NO_x, CO, and O_2 (or CO_2) not monitored with PEMS. As an alternative to using PEMS to monitor O_2 (or CO_2), subsection (b) of this section or similar alternative method approved by the Executive Director and the United States Environmental Protection Agency (EPA) may be used. Any PEMS shall meet the requirements of §117.219 of this title (relating to Notification, Recordkeeping, and Reporting Requirements) and all the requirements of 40 CFR 75, Subpart E, except that the following alternatives or exceptions may be made:

(1) Alternatives to 40 CFR 75, Subpart E which the owner or operator demonstrates to the satisfaction of the TNRCC and EPA to be substantially equivalent to the requirements of 40 CFR 75, Subpart E;

(2) Requirements of 40 CFR 75, Subpart E which the owner or operator demonstrates to the satisfaction of the TNRCC are not applicable; and

(3) As an alternative to the test procedure of Subpart E for initial certification of any unit while firing its primary fuel, the owner or operator:

(A) May perform the following initial certification tests:

(i) Conduct initial relative accuracy test audit (RATA) pursuant to 40 CFR Part 60, Appendix B, Performance Specification 2, subsection 4.3 (pertaining to NO_x); Performance Specification 3, subsection 2.3 (pertaining to O_2 or CO_2); and Performance Specification 4, and section 2.3 (pertaining to CO) at low, medium, and high levels of the key operating parameter affecting NO_x; and

(ii) Conduct an F-test, a t-test, and a correlation analysis pursuant to 40 CFR 75, Subpart E at low, medium, and high levels of the key operating parameter affecting NO_x. Calculations shall be based on a minimum of 30 successive emission data points at each tested level which are either 15-minute averages, 20-minute averages, or hourly averages. The F-test shall separately be performed at each tested level while the t-test and the correlation analysis shall be performed using all data collected at the three tested levels; and

(B) Shall further demonstrate PEMS accuracy with the following tests:

(i) For each of the three successive quarters following the quarter in which initial certification was conducted, demonstrate accuracy and precision of PEMS for at least one unit of a category of equipment by performing RATA and statistical testing in accordance with subparagraph (A) of this paragraph; and

(ii) For each unit and semiannually thereafter, conduct RATA pursuant to 40 CFR 60, Appendix B, Performance Specification 2, subsection 4.3 (pertaining to NO_x); Performance Specification 3, subsection 2.3 (pertaining to O_2 or CO_2); and Performance Specification 4, subsection 2.3 (pertaining to CO) at normal load operations. RATA may be performed on an annual basis rather than on a semiannual basis if the relative accuracy during the previous audit for the NO_x, CO, and O_2 (or CO_2) monitors is less than or equal to 7.5 percent; and

(iii) For each alternative fuel fired in a unit, the PEMS shall be certified in accordance with subparagraph (A) of this paragraph unless the alternative fuel effects on NO_x, CO, and O_2 (or CO_2) emissions were addressed in the model training process.

(d) In addition to the totalizing fuel flow meters specified in subsections (a), (b), and (c) of this section, the owner or operator shall install and maintain totalizing fuel flow meters (for natural gas, refinery or process fuel gas, and fuel oil streams) on an individual unit basis on the following units:

(1) process heaters and commercial, institutional, and industrial boilers, including boilers and industrial furnaces regulated as existing facilities by the EPA at 40 CFR Part 266, Subpart H, and gas turbine supplemental waste heat recovery units, with a rated heat input greater than or equal to 40.0 MMBtu/hr and less than 100.0 MMBtu/hr;

(2) low annual capacity factor boilers and process heaters as defined in §117.010 of this title (relating to Definitions);

(3) lean-burn, stationary, reciprocating internal combustion engines which are located in the Houston/Galveston ozone nonattainment area and rated 150 horsepower (hp) or greater, or located in the Beaumont/ Port Arthur ozone nonattainment area and rated 300 hp or greater, operated 850 or more hours per year;

(4) stationary gas turbines with a MW rating greater than or equal to 1.0 MW and less than 30.0 MW operated more than 850 hours per year; and

(5) supplemental fuel fed to fluid catalytic cracking unit boilers.

(e) The owner or operator of any stationary gas engine subject to the emission specifications of §117.205 or §117.207 of this title shall install and maintain a totalizing fuel flow meter and perform biennial stack testing of engine emissions of NO_x and CO, measured in accordance with the methods specified in §117.211(e) of this title (relating to Initial Demonstration of Compliance). In lieu of performing stack sampling on a biennial calendar basis, an owner or operator may elect to install and operate an elapsed operating time meter and shall test the engine within 15,000 hours of engine operation after the previous emission test. The owner or operator who elects to test on an operating hour schedule shall submit, in writing, to the TNRCC and any local air pollution agency having jurisdiction, biennially after the initial demonstration of compliance, documentation of the actual recorded hours of engine operation since the previous emission test, and an estimate of the date of the next required sampling.

(f) The owner or operator of any stationary gas turbine rated less than 30 MW using steam or water injection to comply with the emission specifications of §117.205 or §117.207 of this title shall either:

(1) install, calibrate, maintain, and operate a CEMS in compliance with subsection (b) of this section or a PEMS in compliance with subsection (c) of this section; or

(2) install, calibrate, maintain, and operate a continuous monitoring system to monitor and record the average hourly fuel and steam or water consumption. The system shall be accurate to within ± 5.0%. The steam-to-fuel or water-to-fuel ratio monitoring data shall constitute the method for demonstrating continuous compliance with the applicable emission specification of §117.205 or §117.207 of this title. Steam or water injection control algorithms are subject to Executive Director approval.

(g) The owner or operator of any low annual capacity factor stationary gas turbine or stationary internal combustion engine as defined in §117.10 of this title shall record the operating time with an elapsed run time meter.

(h) The owner or operator of any gas-fired boiler or process heater firing gaseous fuel which contains more than 50% hydrogen (H_2) by volume, shall sample, analyze, and record every three hours the fuel gas composition to comply with the emission specifications of §117.205 or §117.207 of this title. The total H_2 volume flow in all gaseous fuel streams to the unit will be divided by the total gaseous volume flow to determine the volume percent of H_2 in the fuel supply to the unit. Fuel gas analysis shall be tested according to American Society of Testing and Materials (ASTM) Method D1945-81 or ASTM Method D2650-83, or other methods which are demonstrated to the satisfaction of the Executive Director and the EPA to be equivalent. A gaseous fuel stream containing 99% H_2 by volume or greater may use the following procedure to be exempted from the sampling and analysis requirements of this subsection.

(1) A fuel gas analysis shall be performed initially using one of the test methods in this subsection to demonstrate that the gaseous fuel stream is 99% H_2 by volume or greater.

(2) The process flow diagram of the process unit which is the source of the H_2 shall be supplied to the TNRCC to illustrate the source and supply of the hydrogen stream.

(3) The owner or operator shall certify that the gaseous fuel stream containing H_2 will continuously remain, as a minimum, at 99% H_2 by volume or greater during its use as a fuel to the combustion unit.

(i) After the initial demonstration of compliance required by §117.211 of this title, compliance with either §117.205 or §117.207 of this title, as applicable, shall be determined by the methods required in this section. For enforcement purposes, the Executive Director may also use other TNRCC compliance methods to determine whether the source is in compliance with applicable emission limitations.

(j) If compliance with §117.205 of this title is selected, no unit subject to §117.205 of this title shall be operated at an emission rate higher than that allowed by the emission specifications of §117.205 of this title. If compliance with §117.207 of this title is selected, no unit subject to §117.207 of this title shall be operated at an emission rate higher than that approved by the Executive Director pursuant to §117.215(b)(4) of this title (relating to Final Control Plan Procedures).

(k) The owner or operator of any low annual capacity factor boiler, process heater, stationary gas turbine, or stationary internal combustion engine, as defined in §117.10 of this title, shall notify the Executive Director within seven days if the Btu/yr or hour-per-year (hr/yr) limit specified in §117.10 of this title, as appropriate, is exceeded. If the Btu/yr or hr/yr limit, as appropriate, is exceeded, the exemption from the emission specifications of §117.205 of this title shall be permanently withdrawn. Within 90 days after loss of the exemption, the owner or operator shall submit a compliance plan detailing a plan to meet the applicable compliance limit as soon as possible, but no later than 24 months after exceeding the Btu/yr or hr/yr limit, as appropriate. Included with this compliance plan, the owner or operator shall submit a schedule of increments of progress for the installation of the required control equipment. This schedule shall be subject to the review and approval of the Executive Director.

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§117.215. Final Control Plan Procedures.

(a) For sources complying with §117.205 of this title (relating to Emission Specifications), the owner or operator of an affected source shall submit a final control report to show compliance with the requirements of §117.205 of this title by the date specified in §117.520(6) of this title (relating to Compliance Schedule For Commercial, Institutional, and Industrial Combustion Sources). The report shall include a list of all affected units showing the method of control of nitrogen oxides (NO_x) emissions for each unit and the results of testing required in §117.211 of this title (relating to Initial Demonstration of Compliance).

(b) For sources complying with §117.207 of this title (relating to Alternative Plant-Wide Emission Specifications), the owner or operator of an affected source shall submit a final control plan to show attainment of the requirements of §117.207 of this title by the date specified in §117.520(6) of this title. The owner or operator shall:

(1) assign to each affected boiler or process heater the maximum allowable NO_x emission rate in pound per million (MM) Btu (rolling 30-day average), or in pounds per hour (block one-hour average) while firing gaseous or liquid fuel, which are allowable for that unit under the requirements of §117.207 of this title;

(2) assign to each affected stationary gas turbine the maximum allowable NO_x emission in parts per million by volume at 15% oxygen, dry basis on a block one-hour average;

(3) assign to each affected stationary internal combustion engine the maximum allowable NO_x emission rate in grams per horsepower-hour on a block one-hour average;

(4) submit a list to the Executive Director for approval of the maximum allowable NO_x

emission rates identified in paragraphs (1)-(3) of this subsection and maintain a copy of the approved list for verification of continued compliance with the requirements of §117.207 of this title;

(5) submit a description of the NO_x control method used to achieve compliance with §117.207 of this title, and the results of testing for each unit in accordance with the requirements of §117.211 of this title. For boilers and process heaters complying with a pound per MMBtu emission limit on a rolling 30-day average, this information may be submitted according to the schedule given in §117.520(4) of this title; and

(6) submit a list summarizing the results of testing of each unit at maximum rated capacity, in accordance with the requirements of §117.211(e), (f)(2), and (f)(3) of this title.

(c) For sources complying with §117.223 of this title (relating to Source Cap), the owner or operator of an affected source shall submit a final control plan to show attainment of the requirements of §117.223 of this title by the date specified in §117.520(6) of this title.

Adopted 05/25/94 Effective 06/23/94

§117.217. Revision of Final Control Plan.

A revised final control plan may be submitted by the owner or operator, along with any required permit applications. Such a plan shall adhere to the emission limits and the final compliance dates of this undesignated head (relating to Commercial, Institutional, and Industrial Sources). For sources complying with §117.205 of this title (relating to Emission Specifications), or §117.207 of this title (relating to Alternative Plant-Wide Emission Specifications), replacement new units may be included in the control plan. For sources complying with §117.223 of this title (relating to Source Cap), any new unit shall be included in the source cap, if the unit belongs to an equipment category which is included in the source cap. The revision of the final control plan shall be subject to the review and approval of the Executive Director.

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§117.219. Notification, Recordkeeping, and Reporting Requirements.

(a) For units subject to the exemptions allowed under §117.203(a) of this title (relating to Exemptions), hourly records shall be made of start-up and/or shutdown events and maintained for a period of at least two years. Records shall be available for inspection by the Texas Natural Resource Conservation Commission (TNRCC), United States Environmental Protection Agency (EPA), and any local air pollution control agency having jurisdiction upon request. These records shall include, but are not limited to: type of fuel burned; quantity of each type fuel burned; and the date, time, and duration of the event.

(b) The owner or operator of an affected source shall submit notification to the Executive Director, as follows:

(1) verbal notification of the date of any initial demonstration of compliance testing conducted under §117.211 of this title (relating to Initial Demonstration of Compliance) at least 15 days prior

to such date followed by written notification within 15 days after testing is completed; and

(2) verbal notification of the date of any continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS) performance evaluation conducted under §117.213 of this title (relating to Continuous Demonstration of Compliance) at least 15 days prior to such date followed by written notification within 15 days after testing is completed.

(c) The owner or operator of an affected unit shall furnish the Executive Director and any local air pollution control agency having jurisdiction a copy of any initial demonstration of compliance testing conducted under §117.211 of this title or any CEMS or PEMS performance evaluation conducted under §117.213 of this title, within 60 days after completion of such testing or evaluation. Such results shall be submitted in accordance with the compliance schedule specified in §117.520 of this title (relating to Compliance Schedule For Commercial, Institutional, and Industrial Combustion Sources).

(d) The owner or operator of a unit required to install a CEMS, PEMS, or water-to-fuel or steam-to-fuel ratio monitoring system under §117.213 of this title shall report in writing to the Executive Director on a quarterly basis any exceedance of the applicable emission limitations in §117.205 of this title (relating to Emission Specifications) or §117.207 of this title (relating to Alternative Plant-Wide Emission Specifications) and the monitoring system performance. All reports shall be postmarked or received by the 30th day following the end of each calendar quarter. Written reports shall include the following information:

(1) the magnitude of excess emissions computed in accordance with 40 Code of Federal Regulations, Part 60, §60.13(h), any conversion factors used, the date and time of commencement and completion of each time period of excess emissions, and the unit operating time during the reporting period. For gas turbines using steam-to-fuel or water-to-fuel ratio monitoring to demonstrate compliance in accordance with §117.213(f)(2) of this title, excess emissions are computed as each one-hour period during which the average steam or water injection rate is below the level defined by the control algorithm as necessary to achieve compliance with the applicable emission limitations in §117.205 of this title.

(2) specific identification of each period of excess emissions that occurs during start-ups, shutdowns, and malfunctions of the affected unit, the nature and cause of any malfunction (if known), and the corrective action taken or preventative measures adopted;

(3) the date and time identifying each period during which the continuous monitoring system was inoperative, except for zero and span checks and the nature of the system repairs or adjustments;

(4) when no excess emissions have occurred or the continuous monitoring system has not been inoperative, repaired, or adjusted, such information shall be stated in the report;

(5) if the total duration of excess emissions for the reporting period is less than 1.0% of the total unit operating time for the reporting period and the CEMS, PEMS, or water-to-fuel or steam-to-fuel ratio monitoring system downtime for the reporting period is less than 5.0% of the total unit operating time for the reporting period, only a summary report form (as outlined in the latest edition of the TNRCC "Guidance for Preparation of Summary, Excess Emission, and Continuous Monitoring System Reports") shall be submitted, unless otherwise requested by the Executive Director of the TNRCC. If the total duration

of excess emissions for the reporting period is greater than or equal to 1.0% of the total operating time for the reporting period or the CEMS, PEMS, or water-to-fuel or steam-to-fuel ratio monitoring system downtime for the reporting period is greater than or equal to 5.0% of the total operating time for the reporting period, a summary report and an excess emission report shall both be submitted.

(e) The owner or operator of any rich-burn engine subject to the emission limitations in §117.205 or §117.207 of this title shall report in writing to the Executive Director on a quarterly basis any excess emissions and the air-fuel ratio monitoring system performance. All reports shall be postmarked or received by the 30th day following the end of each calendar quarter. Written reports shall include the following information:

(1) the magnitude of excess emissions (based on the quarterly emission checks of §117.208(d)(7) of this title (relating to Operating Requirements) and the biennial emission testing required for demonstration of emissions compliance in accordance with §117.213(e) of this title, computed in pounds per hour and grams per horsepower-hour, any conversion factors used, the date and time of commencement and completion of each time period of excess emissions, and the engine operating time during the reporting period;

(2) specific identification, to the extent feasible, of each period of excess emissions that occurs during start-ups, shutdowns, and malfunctions of the engine, catalytic converter, or air-fuel ratio controller, the nature and cause of any malfunction (if known), and the corrective action taken or preventative measures adopted.

(f) The owner or operator of an affected unit shall maintain written records of all continuous emissions monitoring and demonstration of compliance test results, hours of operation, and fuel usage rates. Such records shall be kept for a period of at least two years and shall be made available upon request by authorized representatives of the TNRCC, EPA, or local air pollution control agencies having jurisdiction. The emission monitoring (as applicable) and fuel usage records for each unit shall be recorded and maintained:

(1) on an hourly basis for units complying with an emission limit enforced on a block one-hour average;

(2) on a daily basis for units complying with an emission limit enforced on a rolling 30-day basis; and

(3) on a monthly basis for units exempt from the emission specifications based on annual heat input or hours of operation per calendar year.

§117.221. Alternative Case Specific Specifications.

Where a person can demonstrate that an affected unit cannot attain the requirements of §117.205 of this title (relating to Emission Specifications), as applicable, the Executive Director, on a case-by-case basis after considering the technological and economic circumstances of the individual unit, may approve emission specifications different from §117.205 of this title for that unit based on the determination that such specifications are the result of the lowest emission limitation the unit is capable of meeting after the application of reasonably available control technology. In determining whether to approve alternative emission specifications, the Executive Director may take into consideration the ability of the plant at which the unit is located to meet emission specifications through plant-wide averaging at maximum capacity. Any person affected by the decision of the Executive Director may appeal to the Commission by filing written notice of appeal with the Executive Director within 30 days after the decision. Such appeal is to be taken by written notification to the Executive Director. Section 103.71 of this title (relating to Request for Action by the Commission) should be consulted for the method of requesting Commission action on the appeal. Executive Director approval does not necessarily constitute satisfaction of all federal requirements nor eliminate the need for approval by the United States Environmental Protection Agency in cases where specified criteria for determining equivalency have not been clearly identified in applicable sections of this undesignated head (relating to Commercial, Institutional, and Industrial Sources).

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§117.223. Source Cap.

(a) An owner or operator may achieve compliance with the emission limits of §117.205 of this title (relating to Emission Specifications) by achieving equivalent nitrogen oxides (NO_x) emission reductions obtained by compliance with a source cap emission limitation in accordance with the requirements of this section. Each equipment category at a source whose individual emission units would otherwise be subject to the NO_x emission limits of §117.205 of this title may be included in the source cap. Any equipment category included in the source cap shall include all emission units belonging to that category. Equipment categories include, but are not limited to, the following: steam generation, electrical generation, and units with the same product outputs, such as ethylene cracking furnaces. All emission units not included in the source cap shall comply with the requirements of §117.205 or §117.207 (relating to Alternative Plant-Wide Emission Specifications) of this title.

(b) The source cap allowable mass emission rate shall be calculated as follows:

(1) A rolling 30-day average emission cap shall be calculated for all emission units included in the source cap using the following equation:

$$\begin{array}{c}\text{NO}_x\ \text{30-day rolling}\\ \text{average emission cap}\\ \text{(lb/day)}\end{array} = \sum_{i=1}^{N} (H_i \times R_i)$$

Where:

i = each emission unit in the emission cap

N = the total number of emission units in the emission cap

H_i = The actual historical average of the daily heat input for each unit included in the source cap, in million (MM) Btu per day, as certified to the Texas Natural Resource Conservation Commission (TNRCC), for a 24 consecutive month period between January 1, 1990 and June 9, 1993, plus one standard deviation of the average daily heat for that period. All sources included in the source cap shall use the same 24 consecutive month period. If sufficient historical data are not available for this calculation, the Executive Director may approve another method for calculating H_i.

R_i = (A) For emission units subject to the federal New Source Review (NSR) requirements of 40 Code of Federal Regulations (CFR) 51.165(a), 40 CFR 51.166, or 40 CFR 52.21, or to the requirements of Chapter 116 of this title (relating to Control of Air Pollution by Permits for New Construction or Modification) which implements these federal requirements, or emission units that have been subject to a New Source Performance Standard requirement of 40 CFR 60 prior to June 9, 1993, R_i is the lowest of the actual emission rate or all applicable federally enforceable emission limitations as of June 9, 1993, in pounds (lb) NO_x per MMBtu, that apply to emission unit *i* in the absence of trading. All calculations of emission rates shall presume that emission controls in effect on June 9, 1993 are in effect for the two-year period used in calculating the actual heat input.

(B) For all other emission units, R_i is the lowest of the reasonably available control technology (RACT) limit of §117.205(b)-(d) or §117.207(f) of this title or the best available control technology limit for any unit subject to a permit issued pursuant to Chapter 116 of this title, in lb NO_x/MMBtu, that applies to emission unit *i* in the absence of trading.

(2) A maximum daily cap shall be calculated for all emission units included in the source cap using the following equation:

$$\begin{array}{c}NO_x \text{ maximum daily cap} \\ \text{(lb/day)}\end{array} = \sum_{i=1}^{N} \left(H_{Mi} \times R_i\right)$$

Where:

i, N, and R_i are defined as in paragraph (1) of this subsection.

H_{mi} = The maximum daily heat input, as certified to the TNRCC, allowed or possible (whichever is lower) in a 24-hour period.

(3) Each emission unit included in the source cap shall be subject to the requirements of both paragraphs (1) and (2) of this subsection at all times.

(4) The owner or operator at its option may include any of the entire classes of exempted units listed in §117.207(f) of this title in a source cap. Such units shall be required to reduce emissions available for use in the cap by an additional amount calculated in accordance with the United States Environmental Protection Agency's proposed Economic Incentive Program rules for offset ratios for trades between RACT and non-RACT sources, as published in the February 23, 1993, Federal Register (58 FR 11110).

(5) For stationary internal combustion engines, the source cap allowable emission rate shall be calculated in lbs per hour using the procedures specified in §117.207(g)(2) of this title.

(6) For stationary gas turbines, the source cap allowable emission rate shall be calculated in lbs per hour using the procedures specified in §117.207(g)(3) of this title.

(c) The owner or operator who elects to comply with this section shall:

(1) For each unit included in the source cap, either:

(A) Install, calibrate, maintain, and operate a continuous exhaust NO_x monitor, carbon monoxide (CO) monitor, an oxygen (O_2) (or carbon dioxide (CO_2)) diluent monitor, and a totalizing fuel flow meter in accordance with the requirements of §117.213(b) of this title (relating to Continuous Demonstration of Compliance). The required continuous emissions monitoring systems (CEMS) and fuel flow meters shall be used to measure NO_x, CO, and O_2 (or CO_2) emissions and fuel use for each affected unit and shall be used to demonstrate continuous compliance with the source cap;

(B) Install, calibrate, maintain, and operate a predictive emissions monitoring system (PEMS) and a totalizing fuel flow meter in accordance with the requirements of §117.213(c) of this title. The required PEMS and fuel flow meters shall be used to measure NO_x, CO, and O_2 (or CO_2) emissions and fuel flow for each affected unit and shall be used to demonstrate continuous compliance with the source cap; or

(C) For units not subject to continuous monitoring requirements, as provided for in §117.213(a) of this title, and units belonging to the equipment classes listed in §117.207(f) of this title, the owner or operator may use the maximum emission rate as measured by hourly emission rate testing conducted in accordance with §117.211(e) of this title (relating to Initial Demonstration of Compliance) in lieu of CEMS or PEMS. Emission rates for these units shall be limited to the maximum emission rates obtained from testing conducted under §117.211(e) of this title.

(2) For each operating unit equipped with CEMS, the owner or operator shall either use a PEMS pursuant to §117.213(c) of this title, or the maximum emission rate as measured by hourly emission rate testing conducted in accordance with §117.211(e) of this title, to provide emissions compliance data during periods when the CEMS is off-line. The methods specified in 40 CFR 75.46 shall be used to provide emissions substitution data for units equipped with PEMS.

(d) The owner or operator of any units subject to a source cap shall maintain daily records indicating the NO_x emissions from each source and the total fuel usage for each unit and include a total NO_x emissions summation and total fuel usage for all units under the source cap on a daily basis. Records shall also be retained in accordance with §117.219 of this title (relating to Notification, Recordkeeping, and Reporting Requirements).

(e) The owner or operator of any units operating under this provision shall report any exceedance of the source cap emission limit within 48 hours to the appropriate regional office. The owner or operator shall then follow up within 21 days of the exceedance with a written report which includes an analysis of the cause for the exceedance with appropriate data to demonstrate the amount of emissions in excess of the applicable limit and the necessary corrective actions taken by the company to assure future compliance. Additionally, the owner or operator shall submit quarterly reports for the monitoring systems in accordance with §117.219 of this title.

(f) The owner or operator shall demonstrate initial compliance with the source cap in accordance with the schedule specified in §117.520 of this title (relating to Compliance Schedule for Commercial, Institutional, and Industrial Combustion Sources).

(g) A unit which has operated since November 15, 1990 and has since been permanently retired or decommissioned and rendered inoperable prior to June 9, 1993 may be included in the source cap emission limit under the following conditions:

(1) the unit shall have actually operated since November 15, 1990;

(2) for purposes of calculating the source cap emission limit, the applicable emission limit for retired units shall be calculated in accordance with subsection (b) of this section;

(3) the actual heat input shall be calculated according to subsection (b)(1) of this section. If the unit was not in service 24 consecutive months between January 1, 1990 and June 9, 1993, the actual heat input shall be the average daily heat input for the continuous time period that the unit was in service, plus one standard deviation of the average daily heat input for that period. The maximum heat input shall be the maximum heat input, as certified to the TNRCC, allowed or possible (whichever is lower) in a 24-hour period;

(4) the owner or operator shall certify the unit's operational level and maximum rated capacity; and

(5) emission reductions from shutdowns or curtailments which have not been used for netting or offset purposes under the requirements of Chapter 116 of this title or have not resulted from any other state or federal requirement may be included in the baseline for establishing the cap.

(h) A unit which has been shutdown and rendered inoperable after June 9, 1993, but not permanently retired, should be identified in the initial control plan and may be included in the source cap.

(i) An owner or operator who chooses to use the source cap option shall include in the initial control plan required to be filed under §117.209 of this title (relating to Initial Control Plan Procedures) a plan for initial compliance. The owner or operator shall include in the initial control plan the identification of the election to use the source cap procedure as specified in this section to achieve compliance with this section and shall specifically identify all sources that will be included in the source cap. The owner or operator shall also include in the initial control plan the method of calculating the actual heat input for each unit included in the source cap, as specified in subsection (b)(1) of this section. An owner or operator who chooses to use the source cap option shall include in the final control plan procedures of §117.215 of this title (relating to Final Control Plan Procedures) the information necessary under this section to demonstrate final compliance with the source cap.

(j) For the purposes of determining compliance with the source cap emission limit, the contribution of each affected unit that is operating during a startup, shutdown, or upset period shall be calculated from the NO_x emission rate, as measured by the initial demonstration of compliance, for that unit, unless the owner or operator provides data demonstrating to the satisfaction of the Executive Director that actual emissions were less than maximum emissions during such periods.

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